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1

Chemical Composition Determines Behavior Of Reservoir Fluids

The most important factors in classifying the five types of reservoir fluids are the differences in composition. These also affect the sizes and shapes of each fluid's phase diagram. Further, phase diagram shapes affect the actions of the fluids in the reservoir. Subsequent parts of this article will address fluid classification using the initial gas-oil ratio, stock-tank liquid gravity, and stock-tank liquid color.

Petroleum reservoir fluids can be classified into five types–black oils, volatile oils, retrograde gas-condensates, wet gases, and dry gases.[1,2] Each type is produced by different engineering techniques.

The type of fluid is critical to production decisions and, therefore, must be determined early in the life of a reservoir. The reservoir fluid type determines the:

- Method of fluid sampling.
- Laboratory tests used in analyzing the samples.
- Surface equipment types and sizes.
- Procedures for determining oil and gas in place.
- Techniques for predicting oil and gas reserves.
- Processes for predicting future production rates.
- Plan of depletion.
- Selection of secondary or enhanced recovery methods.

Reservoir fluid type can be confirmed only by observing a representative sample of the fluid in a laboratory. However, readily available production data usually will indicate the type of fluid in the reservoir.

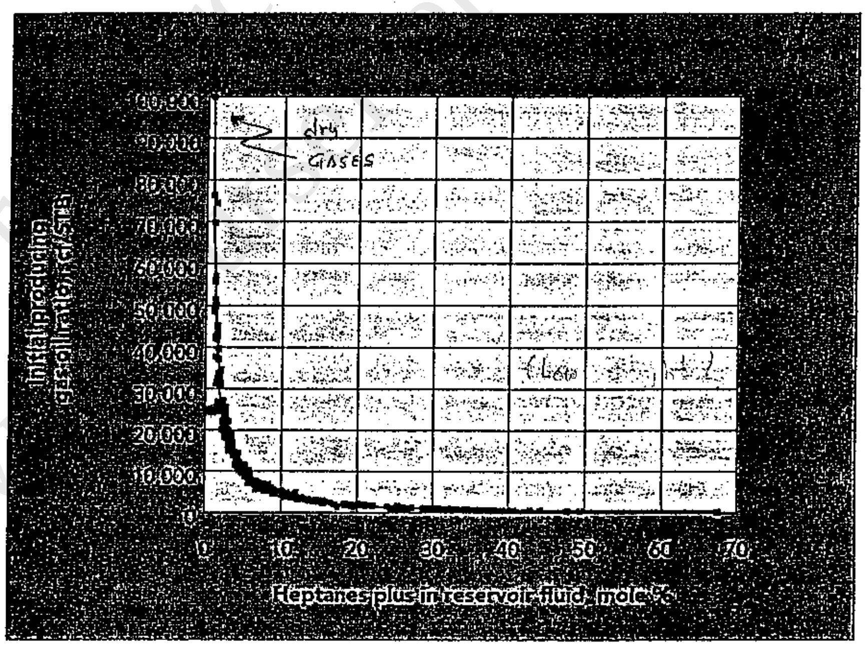

Fig. 1. The initial producing gas-oil ratio is higher for gases, which are represented in the upper left part of the graph, than for black oils, which are represented in the lower right portion of the graph. Other fluids exist in a continuum between dry gas and black oils.

Initial producing gas-oil ratio, stock-tank liquid gravity, and stock-tank oil color are used for classifying fluids. Initial producing gas-oil ratio is the most important of these indicators, but stock-tank oil gravity and color are good validators.[2,3]

The fluid types discussed in this

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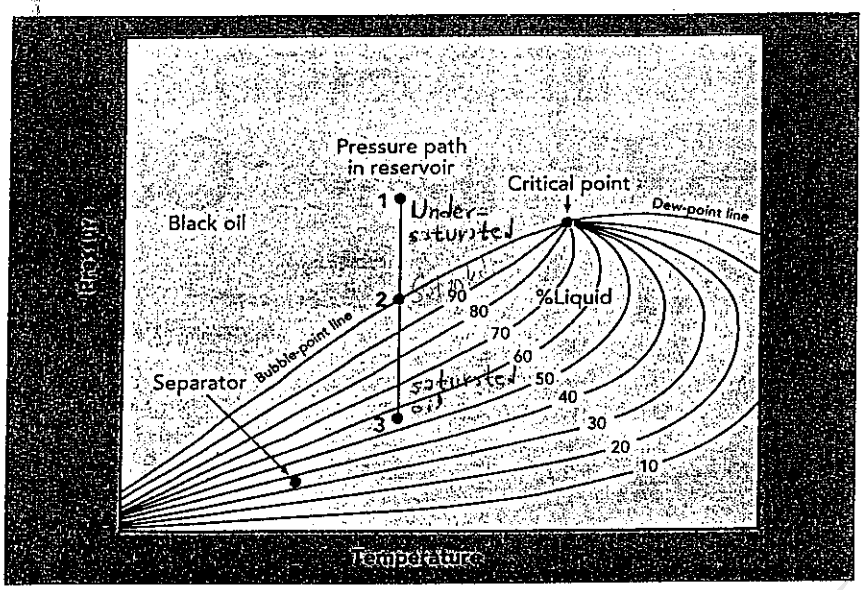

Fig. 2. In the phase diagram of typical black oil, line 123 represents the pressure depletion path at reservoir temperature. Black oil critical points occur at temperatures much higher than reservoir temperature.

series of articles are defined for engineering purposes. These should not be confused with the reservoir fluid descriptions defined by legal agencies which regulate the petroleum industry. The regulatory definitions of oil, crude oil, condensate, gas, natural gas, and casing-head gas are not related to these engineering definitions and often contradict them.

Black oils and volatile oils are liquids in the reservoir, exhibit bubble points as reservoir pressure is decreased during production, and release gas in the reservoir pore space at pressures below the bubble point. However, the "oil material balance equations," which are used for black oils, will give incorrect results for volatile oils, because the behavior of volatile oils does not fit the assumptions inherent in derivation of these equations.[4] Incidentally, black oils are not necessarily black in color and volatile oils do not necessarily produce more surface gas than black oils.

Retrograde gases, wet gases, and dry gases are initially all gas in the reservoir. Retrograde gases exhibit dew points as reservoir pressure is reduced and release increasing volumes of liquid condensate into the pore space as pressure is reduced below the dew point. This condensate seldom flows and is lost to production.

Wet gases and dry gases remain gaseous in the reservoir throughout depletion–neither release condensate in the reservoir. The difference between the two is wet gases release condensate as pressure and temperature are reduced to separator conditions and dry gases remain entirely gaseous at the surface. Note that the words "wet" and "dry" as used in this classification system do not refer to the presence or absence of water or water vapor. Water is always present in petroleum reservoirs, and all gases normally are saturated with water vapor. However, water is excluded from the discussions in this series of articles.

The "gas material balance equation" was derived originally for dry gases. But the equation can be used for wet gases if the equivalent gaseous volume of condensate is included in the cumulative gas production and the quantity and properties of the condensate are added to the surface gas to determine the properties and quantity of the reservoir gas.[5] And the equation is valid for a retrograde gas if the reservoir is volumetric and two-phase gas com-

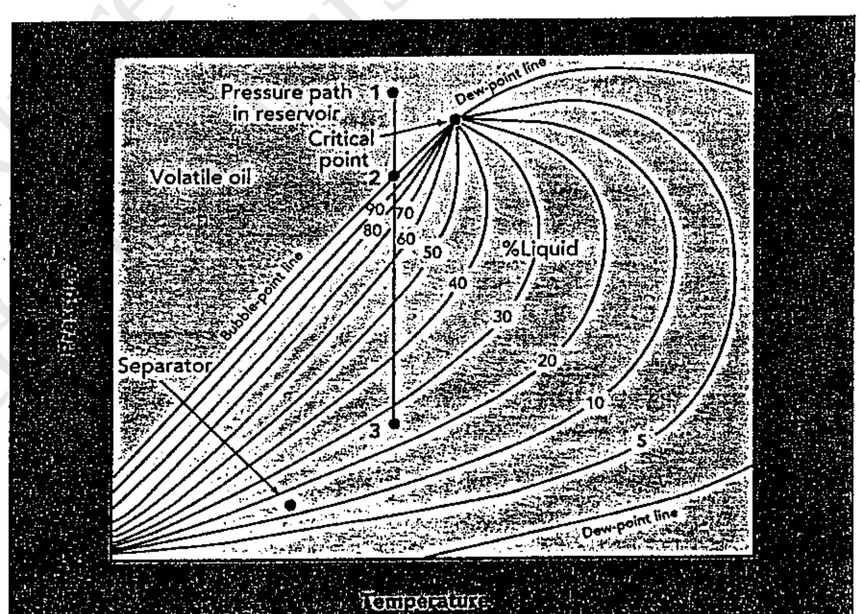

Fig. 3. Compared to black oil, the temperature range of the volatile oil phase diagram is smaller, iso-vol lines shift upward, and the critical point is further down the lefthand slope.

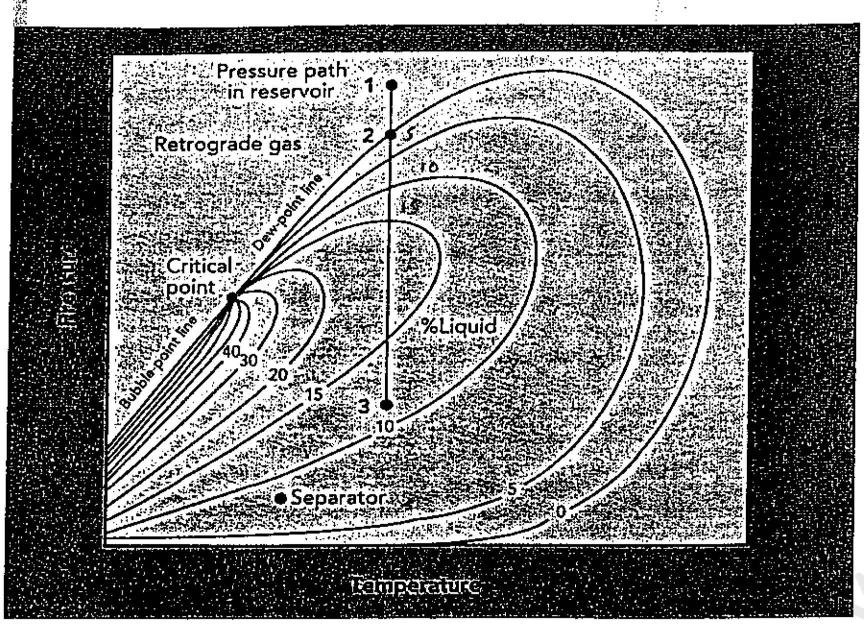

Fig. 4. With fewer heavy molecules than volatile oils, retrograde gases have a critical temperature less than reservoir temperature. Line 123 exhibits a dew point.

pressibility factors are used.[6,7]

Composition is the controlling factor for the behavior described above. Black oils are mixtures of thousands of different chemical species ranging from methane to large, heavy, virtually non-volatile molecules. Volatile oils contain fewer of the heavier molecules. Retrograde gases have even fewer of the heavy ends, wet gases still fewer, and dry gases are essentially pure methane.

The heavy components in the petroleum mixtures have the strongest effect on the characteristics of the fluids. Normally, laboratory tests combine the heavy components as a "heptanes plus" fraction. Fig. 1 illustrates the effect of this heavy fraction on the most important fluid type indicators–the initial producing gas-oil ratio.

Of the five fluids, black oils are represented at the lower right end of the data (black oils have the lowest initial gas-oil ratios and the highest concentration of heavy components). Dry gases are located at the upper left of the graph. The other fluids exist in a continuum between these two. This figure is not a correlation–the gas-oil ratios are not normalized to any standard surface operating conditions. However, the data will be used in ensuing articles to aid understanding of the differences among the five fluids.

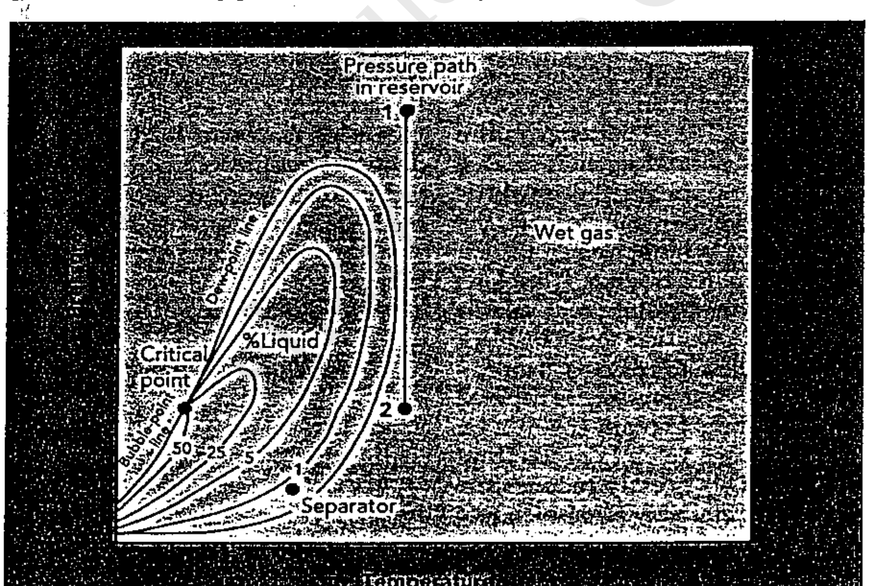

Fig. 5. The pressure depletion path (line 12) of a wet gas does not enter the two-phase region since the phase diagram covers a much smaller temperature range.

Phase Diagrams

Phase diagrams are plots of pressure against temperature that show conditions for which a particular substance will exist as a liquid, gas, or both. Phase diagrams show the phases of petroleum fluids in the reservoir. When combined with knowledge of the effective permeabilities and viscosities, the diagrams also indicate which phases are flowing in the reservoir.

The wide range of sizes and masses of molecules in a black oil mixture dictates that the phase diagram will cover a wide range of temperatures. Fig. 2 shows the phase diagram of a typical black oil.

The region in the upper left part of the diagram gives conditions in which the mixture is a liquid. A liquid phase is verified by the fact that as pressure is reduced at constant temperature, gas is released, first as a bubble, then in increasing amounts as the pressure is reduced below the bubble point. The upper right part of the diagram gives conditions in which the mixture is a gas. Again the test is what happens when the pressure is reduced at constant temperature. This time the mixture has a dew point, and increasing amounts of liquid are formed as pressure is reduced below this point.

The lines representing the bubble-point and dew-point pressures meet at the critical point. Lines representing the volume of liquid in the two-phase region of the diagram are called iso-vols. They also converge to the critical point. Observe that the critical point is on the lefthand slope of the phase envelope. The critical point in naturally occurring petroleum fluids normally does not appear to the right of the top of the diagram. Only

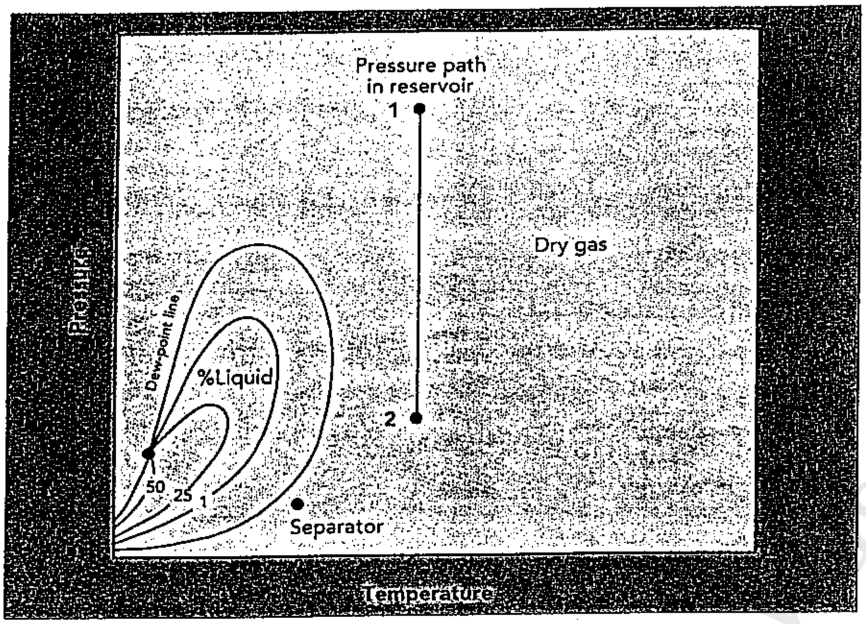

Fig. 6. Illustrating dry gas is virtually pure methane, the two-phase envelope of the phase diagram lies below reservoir and surface conditions.

those fluids which are deficient in intermediate components (sometimes found in South Louisiana) or have a high nitrogen content will have critical points to the right of the top of the phase envelope.

The critical points and dew-point lines for black oils always occur at temperatures much higher than reservoir temperatures. Line 123 on the diagram represents the pressure depletion path at reservoir temperature. Reservoir temperature is well below the critical point.

If initial reservoir pressure is represented by point 1, the oil is "undersaturated." As pressure depletion proceeds from point 1 to point 2, reservoir gas exists–a single phase (oil) is flowing, and the gas-oil ratio at surface conditions is constant. The amount of oil production required to cause the pressure to fall from point 1 to point 2 is a small fraction of the total production. Without a natural water drive, the only energy available to resist pressure reduction comes from the expansion of the oil and reservoir rock, which is small.

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When a gas cap is present, the bubble-point of the oil will be equal to the initial reservoir pressure represented by point 2 on the diagram

As production continues and pressure is reduced along path 23, gas comes out of solution in the reservoir. The oil is "saturated." Notice the iso-vol lines are spaced fairly evenly. Thus oil saturation remains relatively high, which maintains the effective permeability to oil at a reasonable level. At point 3 the effective permeabilities to oil and gas are about equal. But the viscosity of the oil is about two orders of magnitude larger than the viscosity of the gas. Therefore, at point 3, more than 90% of the reservoir flow stream volume is gas.

Volatile oils have fewer heavy molecules than black oils. This causes three important changes in the phase diagram (Fig. 3).[1] The temperature range of the phase diagram is smaller, iso-vol lines are shifted upwards toward the bubble-point line, and the critical point is further down the left hand slope of the diagram. Therefore, the critical temperature of a volatile oil, is much lower than that for a black oil, and is close to reservoir temperature. As reservoir pressure is depleted below the bubble-point (point 2 on line 123), large volumes of gas leave solution. This greatly reduces the effective permeability to oil such that the reservoir flow stream becomes mostly gas within a few hundred psi below the bubble point. The effective permeability to oil becomes virtually zero and the flow stream is essentially all gas long before the reservoir pressure reaches point 3 on Fig. 3.[1]

Retrograde gases have even fewer heavy molecules than volatile oils. The phase diagram of a retrograde gas shows the same three changes (Fig. 4).[1] The critical point shifts far enough down the phase diagram so the critical temperature is less than reservoir temperature. The pressure depletion path in the reservoir (line 123) now exhibits a dew point. Retrograde condensate appears in the reservoir pore spaces at pressures below the dew point. Throughout most of the reservoir, the effective permeability to this condensate is zero and little is produced. Near the well bores, where gas flow rate is high, some of the condensate flows.

Along line 23, the condensate builds up at first and then revaporizes at the lower pressures. This effect is minimized in the reservoir. The overall composition of the reservoir fluid becomes heavier as the lighter gas is produced and the heavier condensate remains behind. This causes a shift in the phase diagram downward and to the right, reducing the amount of revaporization.

The composition of a wet gas contains still fewer heavy molecules. Since, the phase diagram in Fig. 5 covers a much smaller temperature range, the pressure depletion path in the reservoir does not enter the two-phase region.[1] The reservoir fluid is gas throughout the life of the reservoir. However, separator conditions lie within the two-phase envelope, indicating that some liquid will condense at the surface.

Finally, dry gas is virtually pure methane. The two-phase envelope is small and lies below reservoir conditions and surface conditions (Fig. 6).[1] The fluid is solely gas in the reservoir and at the surface.

Subsequent parts of this series will address:

- Which of these fluids are found together when the reservoir has two phases.
- The differences between black oils and volatile oils.
- The differences between volatile oils and retrograde gases.
- Why retrograde condensate does not flow.

When wet gas calculation techniques can be applied to retrograde gases.

Calculational techniques for determining fluids in place and predicting future recovery and reserves.

Emphasis will be on understanding these fluids so that calculations and decisions leading to improved recovery will be possible. ●

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